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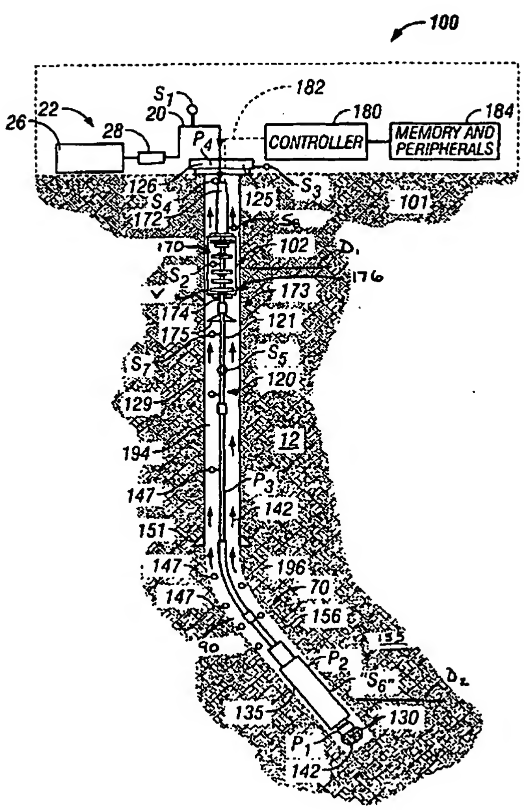
(54) Title: ACTIVE CONTROLLED BOTTOMHOLE PRESSURE SYSTEM & METHOD BACKGROUND OF THE INVENTION




(57) Abstract: A wellbore drilling system has an umbilical that carries a drill bit in a wellbore. Drilling fluid pumped into the umbilical discharges at the drill bit bottom and returns through an annulus between the umbilical and the wellbore carrying entrained drill cuttings. An active differential pressure device (APD device), such as a jet pump, turbine or centrifugal pump, in fluid communication with the returning fluid creates a differential pressure across the device, which alters the pressure below or downhole of the device. The APD device can be driven by a positive displacement motor, a turbine, an electric motor, or a hydraulic motor. A controller controls the operation of the APD device in response to programmed instructions and/or one or more parameters of interest detected by one or more sensors. A preferred system is a closed loop system that maintains the wellbore at under-balance condition, at-balance condition or over-balance condition.

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# ACTIVE CONTROLLED BOTTOMHOLE PRESSURE SYSTEM & METHOD

## BACKGROUND OF THE INVENTION

Field of the Invention

This invention relates generally to oilfield wellbore drilling systems and more particularly to drilling systems that utilize active control of bottomhole pressure or equivalent circulating density during drilling of the wellbores.

Background of the Art

Oilfield wellbores are drilled by rotating a drill bit conveyed into the wellbore by a drill string. The drill string includes a drill pipe (tubing) that has at its bottom end a drilling assembly (also referred to as the "bottomhole assembly" or "BHA") that carries the drill bit for drilling the wellbore. The drill pipe is made of jointed pipes. Alternatively, coiled tubing may be utilized to carry the drilling of assembly. The drilling assembly usually includes a drilling motor or a "mud motor" that rotates the drill bit. The drilling assembly also includes a variety of sensors for taking measurements of a variety of drilling, formation and BHA parameters. A suitable drilling fluid (commonly referred to as the "mud") is supplied or pumped under pressure from a source at the surface down the tubing. The drilling fluid drives the mud motor and then discharges at the bottom of the drill bit. The drilling fluid returns uphole via the annulus between the drill string and the wellbore inside and carries with it pieces of formation (commonly referred to as the "cuttings") cut or produced by the drill bit in drilling the wellbore.

For drilling wellbores under water (referred to in the industry as "offshore" or "subsea" drilling) tubing is provided at a work station (located on a vessel or platform). One or more tubing injectors or rigs are used to move the tubing into and out of the wellbore. In riser-type drilling, a riser, which is formed by joining sections of casing or pipe, is deployed between the drilling vessel and the wellhead equipment at the sea bottom and is utilized to guide the tubing to the wellhead. The riser also serves as a conduit for fluid returning from the wellhead to the sea surface.

During drilling, the drilling operator attempts to carefully control the fluid density at the surface so as to control pressure in the wellbore, including the bottomhole pressure. Typically, the operator maintains the hydrostatic pressure of the drilling fluid in the wellbore above the formation or pore pressure to avoid well blow-out. The density of the drilling fluid and the fluid flow rate largely determine the effectiveness of the drilling fluid to carry the cuttings to the surface. One important downhole parameter controlled during drilling is the bottomhole pressure, which in turn controls the equivalent circulating density ("ECD") of the fluid at the wellbore bottom.

This term, ECD, describes the condition that exists when the drilling mud in the well is circulated. The friction pressure caused by the fluid circulating through the open hole and the casing(s) on its way back to the surface, causes an increase in the pressure profile along this path that is different from the pressure profile when the well is in a static condition (i.e., not circulating). In addition to the increase in pressure while circulating, there is an additional increase in pressure while drilling due to the introduction of drill solids into the fluid. This negative effect of the increase in pressure along the annulus of the well is an increase of the pressure which can fracture the formation at the shoe of the last casing. This can reduce the amount of hole that can be drilled before having to set an additional casing. In addition, the rate of circulation that can be achieved is also limited. Also, due to this circulating pressure increase, the ability to clean the hole is severely restricted. This condition is exacerbated when drilling an offshore well. In offshore wells, the difference between the fracture pressures in the shallow sections of the well and the pore pressures of the deeper sections is considerably smaller compared to on shore wellbores. This is due to the seawater gradient versus the gradient that would exist if there were soil overburden for the same depth.

In some drilling applications, it is desired to drill the wellbore at at-balance condition or at under-balanced condition. The term at-balance means that the pressure in the wellbore is maintained at or near the formation

pressure. The under-balanced condition means that the wellbore pressure is below the formation pressure. These two conditions are desirable because the drilling fluid under such conditions does not penetrate into the formation, thereby leaving the formation virgin for performing formation evaluation tests and measurements. In order to be able to drill a well to a total wellbore depth at the bottomhole, ECD must be reduced or controlled. In subsea wells, one approach is to use a mud- filled riser to form a subsea fluid circulation system utilizing the tubing, BHA, the annulus between the tubing and the wellbore and the mud filled riser, and then inject gas (or some other low density liquid) in the primary drilling fluid (typically in the annulus adjacent the BHA) to reduce the density of fluid downstream (i.e., in the remainder of the fluid circulation system). This so-called "dual density" approach is often referred to as drilling with compressible fluids.

Another method for changing the density gradient in a deepwater return fluid path has been proposed, but not used in practical application. This approach proposes to use a tank, such as an elastic bag, at the sea floor for receiving return fluid from the wellbore annulus and holding it at the hydrostatic pressure of the water at the sea floor. Independent of the flow in the annulus, a separate return line connected to the sea floor storage tank and a subsea lifting pump delivers the return fluid to the surface. Although this technique (which is referred to as "dual gradient" drilling) would use a single fluid, it would also require a discontinuity in the hydraulic gradient line between the sea floor storage tank and the subsea lifting pump. This requires close monitoring and control of the pressure at the subsea storage tank, subsea hydrostatic water pressure, subsea lifting pump operation and the surface pump delivering drilling fluids under pressure into the tubing for flow downhole. The level of complexity of the required subsea instrumentation and controls as well as the difficulty of deployment of the system has delayed (if not altogether prevented) the practical application of the "dual gradient" system.

Another approach is described in U.S. Patent Application No. 09/353,275, filed on July 14, 1999 and assigned to the assignee of the present application. The U.S. Patent Application No. 09/353,275 is incorporated herein by reference in its entirety. One embodiment of this application describes a riser less system wherein a centrifugal pump in a separate return line controls the fluid flow to the surface and thus the equivalent circulating density.

The present invention provides a wellbore system wherein the bottomhole pressure and hence the equivalent circulating density is controlled by creating a pressure differential at a selected location in the return fluid path with an active pressure differential device to reduce or control the bottomhole pressure. The present system is relatively easy to incorporate in new and existing systems.

## SUMMARY OF THE INVENTION

The present invention provides wellbore systems for performing downhole wellbore operations for both land and offshore wellbores. Such drilling systems include a rig that moves an umbilical (e.g., drill string) into and out of the wellbore. A bottomhole assembly, carrying the drill bit, is attached to the bottom end of the drill string. A well control assembly or equipment on the well receives the bottomhole assembly and the tubing. A drilling fluid system supplies a drilling fluid into the tubing, which discharges at the drill bit and returns to the well control equipment carrying the drill cuttings via the annulus between the drill string and the wellbore. A riser dispersed between the wellhead equipment and the surface guides the drill string and provides a conduit for moving the returning fluid to the surface.

In one embodiment of the present invention, an active pressure differential device moves in the wellbore as the drill string is moved. In an alternative embodiment, the active differential pressure device is attached to the wellbore inside or wall and remains stationary relative to the wellbore during drilling. The device is operated during drilling, *i.e.*, when the drilling

fluid is circulating through the wellbore, to create a pressure differential across the device. This pressure differential alters the pressure on the wellbore below or downhole of the device. The device may be controlled to reduce the bottomhole pressure by a certain amount, to maintain the bottomhole pressure at a certain value, or within a certain range. By severing or restricting the flow through the device, the bottomhole pressure may be increased.

The system also includes downhole devices for performing a variety of functions. Exemplary downhole devices include devices that control the drilling flow rate and flow paths. For example, the system can include one or more flow-control devices that can stop the flow of the fluid in the drill string and/or the annulus. Such flow-control devices can be configured to direct fluid in drill string into the annulus and/or bypass return fluid around the APD device. Another exemplary downhole device can be configured for processing the cuttings (*e.g.*, reduction of cutting size) and other debris flowing in the annulus. For example, a comminution device can be disposed in the annulus upstream of the APD device.

In a preferred embodiment, sensors communicate with a controller via a telemetry system to maintain the wellbore pressure at a zone of interest at a selected pressure or range of pressures. The sensors are strategically positioned throughout the system to provide information or data relating to one or more selected parameters of interest such as drilling parameters, drilling assembly or BHA parameters, and formation or formation evaluation parameters. The controller for suitable for drilling operations preferably includes programs for maintaining the wellbore pressure at zone at under-balance condition, at at-balance condition or at over-balanced condition. The controller may be programmed to activate downhole devices according to programmed instructions or upon the occurrence of a particular condition.

Exemplary configurations for the APD Device and associated drive includes a moineau-type pump coupled to positive displacement motor/drive

via a shaft assembly. Another exemplary configuration includes a turbine drive coupled to a centrifugal-type pump via a shaft assembly. Preferably, a high-pressure seal separates a supply fluid flowing through the motor from a return fluid flowing through the pump. In a preferred embodiment, the seal is configured to bear either or both of radial and axial (thrust) forces.

In still other configurations, a positive displacement motor can drive an intermediate device such as a hydraulic motor, which drives the APD Device. Alternatively, a jet pump can be used, which can eliminate the need for a drive/motor. Moreover, pumps incorporating one or more pistons, such as hammer pumps, may also be suitable for certain applications. In still other configurations, the APD Device canb be driven by an electric motor. The electric motor can be positioned external to a drill string or formed integral with a drill string. In a preferred arrangement, varying the speed of the electrical motor directly controls the speed of the rotor in the APD device, and thus the pressure differential across the APD Device.

Bypass devices are provided to allow fluid circulation in the wellbore during tripping of the system, to control the operating set points of the APD Device and/or associated drive/motor, and to provide a discharge mechanism to relieve fluid pressure. For examples, the bypass devices can selectively channel fluid around the motor/drive and the APD Device and selectively discharge drilling fluid from the drill string into the annulus. In one arrangement, the bypass device for the pump can also function as a particle bypass line for the APD device. Alternatively, a separate particle bypass can be used in addition to the pump bypass for such a function. Additionally, an annular seal (not shown) in certain embodiments can be disposed around the APD device to enable a pressure differential across the APD Device.

Examples of the more important features of the invention have been summarized (albeit rather broadly) in order that the detailed description thereof that follows may be better understood and in order that the contributions they represent to the art may be appreciated. There are, of

course, additional features of the invention that will be described hereinafter and which will form the subject of the claims appended hereto.

BRIEF DESCRIPTION OF THE DRAWINGS

For detailed understanding of the present invention, reference should be made to the following detailed description of the preferred embodiment, taken in conjunction with the accompanying drawing:

**Figure 1A** is a schematic illustration of one embodiment of a system using an active pressure differential device to manage pressure in a predetermined wellbore location;

**Figure 1B** graphically illustrates the effect of an operating active pressure differential device upon the pressure at a predetermined wellbore location;

**Figure 2** is a schematic elevation view of **Figure 1A** after the drill string and the active pressure differential device have moved a certain distance in the earth formation from the location shown in **Figure 1A**;

**Figure 3** is a schematic elevation view of an alternative embodiment of the wellbore system wherein the active pressure differential device is attached to the wellbore inside;

**Figures 4A-D** are schematic illustrations of one embodiment of an arrangement according to the present invention wherein a positive displacement motor is coupled to a positive displacement pump (the APD Device);

**Figures 5A** and **5B** are schematic illustrations of one embodiment of an arrangement according to the present invention wherein a turbine drive is coupled to a centrifugal pump (the APD Device);

**Figure 6A** is a schematic illustration of an embodiment of an arrangement according to the present invention wherein an electric motor disposed on the outside of a drill string is coupled to an APD Device; and

**Figure 6B** is a schematic illustration of an embodiment of an arrangement according to the present invention wherein an electric motor disposed within a drill string is coupled to an APD Device.

## DETAILED DESCRIPTION OF PREFERRED EMBODIMENTS

Referring initially to **Figure 1A**, there is schematically illustrated a system for performing one or more operations related to the construction, logging, completion or work-over of a hydrocarbon producing well. In particular, **Figure 1A** shows a schematic elevation view of one embodiment of a wellbore drilling system **100** for drilling wellbore **90** using conventional drilling fluid circulation. The drilling system **100** is a rig for land wells and includes a drilling platform **101**, which may be a drill ship or another suitable surface workstation such as a floating platform or a semi-submersible for offshore wells. For offshore operations, additional known equipment such as a riser and subsea wellhead will typically be used. To drill a wellbore **90**, well control equipment **125** (also referred to as the wellhead equipment) is placed above the wellbore **90.** The wellhead equipment **125** includes a blow-out-preventer stack **126** and a lubricator (not shown) with its associated flow control.

This system **100** further includes a well tool such as a drilling assembly or a bottomhole assembly ("BHA") **135** at the bottom of a suitable umbilical such as drill string or tubing **121b** (such terms will be used interchangeably). In a preferred embodiment, the BHA **135** includes a drill bit **130** adapted to disintegrate rock and earth. The bit can be rotated by a surface rotary drive or a motor using pressurized fluid (e.g., mud motor) or an electrically driven motor. The tubing **121** can be formed partially or fully of drill pipe, metal or composite coiled tubing, liner, casing or other known members. Additionally, the tubing **121** can include data and power transmission carriers such fluid conduits, fiber optics, and metal conductors. Conventionally, the tubing **121** is placed at the drilling platform **101**. To drill the wellbore **90**, the BHA **135** is conveyed from the drilling platform **101** to the wellhead equipment **125** and

then inserted into the wellbore **90**. The tubing **121** is moved into and out of the wellbore **90** by a suitable tubing injection system.

During drilling, a drilling fluid from a surface mud system **22** is pumped under pressure down the tubing **121** (a "supply fluid"). The mud system **22** includes a mud pit or supply source **26** and one or more pumps **28**. In one embodiment, the supply fluid operates a mud motor in the BHA **135**, which in turn rotates the drill bit **130**. The drill string **121** rotation can also be used to rotate the drill bit **130**, either in conjunction with or separately from the mud motor. The drill bit **130** disintegrates the formation (rock) into cuttings **147**. The drilling fluid leaving the drill bit travels uphole through the annulus **194** between the drill string **121** and the wellbore wall or inside **196**, carrying the drill cuttings **147** therewith (a "return fluid"). The return fluid discharges into a separator (not shown) that separates the cuttings **147** and other solids from the return fluid and discharges the clean fluid back into the mud pit **26**. As shown in **Figure 1A**, the clean mud is pumped through the tubing **121** while the mud with cuttings **147** returns to the surface via the annulus **194** up to the wellhead equipment **125**.

Once the well **90** has been drilled to a certain depth, casing **129** with a casing shoe **151** at the bottom is installed. The drilling is then continued to drill the well to a desired depth that will include one or more production sections, such as section **155**. The section below the casing shoe **151** may not be cased until it is desired to complete the well, which leaves the bottom section of the well as an open hole, as shown by numeral **156**.

As noted above, the present invention provides a drilling system for controlling bottomhole pressure at a zone of interest designated by the numeral **155** and thereby the ECD effect on the wellbore. In one embodiment of the present invention, to manage or control the pressure at the zone **155**, an active pressure differential device ("APD Device") **170** is fluidicly coupled to return fluid downstream of the zone of interest **155**. The active pressure

differential device is a device that is capable of creating a pressure differential "ΔP" across the device. This controlled pressure drop reduces the pressure upstream of the APD Device **170** and particularly in zone **155**.

The system **100** also includes downhole devices that separately or cooperatively perform one or more functions such as controlling the flow rate of the drilling fluid and controlling the flow paths of the drilling fluid. For example, the system **100** can include one or more flow-control devices that can stop the flow of the fluid in the drill string and/or the annulus **194**. **Figure 1A** shows an exemplary flow-control device **173** that includes a device **174** that can block the fluid flow within the drill string **121** and a device **175** that blocks can block fluid flow through the annulus **194**. The device **173** can be activated when a particular condition occurs to insulate the well above and below the flow-control device **173**. For example, the flow-control device **173** may be activated to block fluid flow communication when drilling fluid circulation is stopped so as to isolate the sections above and below the device **173**, thereby maintaining the wellbore below the device **173** at or substantially at the pressure condition prior to the stopping of the fluid circulation.

The flow-control devices **174, 175** can also be configured to selectively control the flow path of the drilling fluid. For example, the flow-control device **174** in the drill pipe **121** can be configured to direct some or all of the fluid in drill string **121** into the annulus **194**. Moreover, one or both of the flow-control devices **174, 175** can be configured to bypass some or all of the return fluid around the APD device **170**. Such an arrangement may be useful, for instance, to assist in lifting cuttings to the surface. The flow-control device **173** may include check-valves, packers and any other suitable device. Such devices may automatically activate upon the occurrence of a particular event or condition.

The system **100** also includes downhole devices for processing the cuttings (*e.g.*, reduction of cutting size) and other debris flowing in the annulus **194**. For example, a comminution device **176** can be disposed in the annulus **194** upstream of the APD device **170** to reduce the size of entrained cutting and other debris. The comminution device **176** can use known members such as blades, teeth, or rollers to crush, pulverize or otherwise disintegrate cuttings and debris entrained in the fluid flowing in the annulus **194**. The comminution device **176** can be operated by an electric motor, a hydraulic motor, by rotation of drill string or other suitable means. The comminution device **176** can also be integrated into the APD device **170**. For instance, if a multi-stage turbine is used as the APD device **170**, then the stages adjacent the inlet to the turbine can be replaced with blades adapted to cut or shear particles before they pass through the blades of the remaining turbine stages.

Sensors $S_{1-n}$ are strategically positioned throughout the system **100** to provide information or data relating to one or more selected parameters of interest (pressure, flow rate, temperature). In a preferred embodiment, the devices **20** and sensors $S_{1-n}$ communicate with a controller **180** via a telemetry system (not shown). Using data provided by the sensors $S_{1-n}$, the controller **180** maintains the wellbore pressure at zone **155** at a selected pressure or range of pressures. The controller **180** maintains the selected pressure by controlling the APD device **170** (e.g., adjusting amount of energy added to the return fluid line) and/or the downhole devices (e.g., adjusting flow rate through a restriction such as a valve).

When configured for drilling operations, the sensors $S_{1-n}$ provide measurements relating to a variety of drilling parameters, such as fluid pressure, fluid flow rate, rotational speed of pumps and like devices, temperature, weight-on bit, rate of penetration, etc., drilling assembly or BHA parameters, such as vibration, stick slip, RPM, inclination, direction, BHA location, etc. and formation or formation evaluation parameters commonly referred to as measurement-while-drilling parameters such as resistivity,

acoustic, nuclear, NMR, etc. One preferred type of sensor is a pressure sensor for measuring pressure at one or more locations. Referring still to **Fig. 1A**, pressure sensor $\mathbf{P_1}$ provides pressure data in the BHA, sensor $\mathbf{P_2}$ provides pressure data in the annulus, pressure sensor $\mathbf{P_3}$ in the supply fluid, and pressure sensor $\mathbf{P_4}$ provides pressure data at the surface. Other pressure sensors may be used to provide pressure data at any other desired place in the system **100**. Additionally, the system **100** includes fluid flow sensors such as sensor **V** that provides measurement of fluid flow at one or more places in the system.

Further, the status and condition of equipment as well as parameters relating to ambient conditions (e.g., pressure and other parameters listed above) in the system **100** can be monitored by sensors positioned throughout the system **100**: exemplary locations including at the surface **(S1)**, at the APD device **170 (S2)**, at the wellhead equipment **125 (S3)**, in the supply fluid **(S4)**, along the tubing **121 (S5)**, at the well tool **135 (S6)**, in the return fluid upstream of the APD device **170 (S7)**, and in the return fluid downstream of the APD device **170 (S8)**. It should be understood that other locations may also be used for the sensors $\mathbf{S_{1\text{-}n}}$.

The controller **180** for suitable for drilling operations preferably includes programs for maintaining the wellbore pressure at zone **155** at under-balance condition, at at-balance condition or at over-balanced condition. The controller **180** includes one or more processors that process signals from the various sensors in the drilling assembly and also controls their operation. The data provided by these sensors $\mathbf{S_{1\text{-}n}}$ and control signals transmitted by the controller **180** to control downhole devices such as devices **173-176** are communicated by a suitable two-way telemetry system (not shown). A separate processor may be used for each sensor or device. Each sensor may also have additional circuitry for its unique operations. The controller **180**, which may be either downhole or at the surface, is used herein in the generic sense for simplicity and ease of understanding and not as a limitation

because the use and operation of such controllers is known in the art. The controller **180** preferably contains one or more microprocessors or micro-controllers for processing signals and data and for performing control functions, solid state memory units for storing programmed instructions, models (which may be interactive models) and data, and other necessary control circuits. The microprocessors control the operations of the various sensors, provide communication among the downhole sensors and provide two-way data and signal communication between the drilling assembly **30**, downhole devices such as devices **173-175** and the surface equipment via the two-way telemetry. In other embodiments, the controller **180** can be a hydro-mechanical device that incorporates known mechanisms (valves, biased members, linkages cooperating to actuate tools under, for example, preset conditions).

For convenience, a single controller **180** is shown. It should be understood, however, that a plurality of controllers **180** can also be used. For example, a downhole controller can be used to collect, process and transmit data to a surface controller, which further processes the data and transmits appropriate control signals downhole. Other variations for dividing data processing tasks and generating control signals can also be used.

In general, however, during operation, the controller **180** receives the information regarding a parameter of interest and adjusts one or more downhole devices and/or APD device **170** to provide the desired pressure or range or pressure in the vicinity of the zone of interest **155**. For example, the controller **180** can receive pressure information from one or more of the sensors **($S_1$-$S_n$)** in the system **100**. The controller **180** may control the APD Device **170** in response to one or more of: pressure, fluid flow, a formation characteristic, a wellbore characteristic and a fluid characteristic, a surface measured parameter or a parameter measured in the drill string. The controller **180** determines the ECD and adjusts the energy input to the APD device **170** to maintain the ECD at a desired or predetermined value or within

a desired or predetermined range. The wellbore system **100** thus provides a closed loop system for controlling the ECD in response to one or more parameters of interest during drilling of a wellbore. This system is relatively simple and efficient and can be incorporated into new or existing drilling systems and readily adapted to support other well construction, completion, and work-over activities.

In the embodiment shown in **Figure 1A**, the APD Device **170** is shown as a turbine attached to the drill string **121** that operates within the annulus **194**. Other embodiments, described in further detail below can include centrifugal pumps, positive displacement pump, jet pumps and other like devices. During drilling, the APD Device **170** moves in the wellbore **90** along with the drill string **121**. The return fluid can flow through the APD Device **170** whether or not the turbine is operating. However, the APD Device **170**, when operated creates a differential pressure thereacross.

As described above, the system **100** in one embodiment includes a controller **180** that includes a memory and peripherals **184** for controlling the operation of the APD Device **170**, the devices **173-176**, and/or the bottomhole assembly **135**. In **Figure 1A**, the controller **180** is shown placed at the surface. It, however, may be located adjacent the APD Device **170**, in the BHA **135** or at any other suitable location. The controller **180** controls the APD Device to create a desired amount of $\Delta P$ across the device, which alters the bottomhole pressure accordingly. Alternatively, the controller **180** may be programmed to activate the flow-control device **173** (or other downhole devices) according to programmed instructions or upon the occurrence of a particular condition. Thus, the controller **180** can control the APD Device in response to sensor data regarding a parameter of interest, according to programmed instructions provided to said APD Device, or in response to instructions provided to said APD Device from a remote location. The controller **180** can, thus, operate autonomously or interactively.

During drilling, the controller **180** controls the operation of the APD Device to create a certain pressure differential across the device so as to alter the pressure on the formation or the bottomhole pressure. The controller **180** may be programmed to maintain the wellbore pressure at a value or range of values that provide an under-balance condition, an at-balance condition or an over-balanced condition. In one embodiment, the differential pressure may be altered by altering the speed of the APD Device. For instance, the bottomhole pressure may be maintained at a preselected value or within a selected range relative to a parameter of interest such as the formation pressure. The controller **180** may receive signals from one or more sensors in the system **100** and in response thereto control the operation of the APD Device to create the desired pressure differential. The controller **180** may contain pre-programmed instructions and autonomously control the APD Device or respond to signals received from another device that may be remotely located from the APD Device.

**Figure 1B** graphically illustrates the ECD control provided by the above-described embodiment of the present invention and references **Figure 1A** for convenience. **Figure 1A** shows the APD device **170** at a depth **D1** and a representative location in the wellbore in the vicinity of the well tool **30** at a lower depth **D2**. **Figure 1B** provides a depth versus pressure graph having a first curve **C1** representative of a pressure gradient before operation of the system **100** and a second curve **C2** representative of a pressure gradients during operation of the system **100**. Curve **C3** represents a theoretical curve wherein the ECD condition is not present; *i.e.*, when the well is static and not circulating and is free of drill cuttings. It will be seen that a target or selected pressure at depth **D2** under curve **C3** cannot be met with curve **C1**. Advantageously, the system **100** reduces the hydrostatic pressure at depth **D1** and thus shifts the pressure gradient as shown by curve **C3**, which can provide the desired predetermined pressure at depth **D2**. In most instances, this shift is roughly the pressure drop provided by the APD device **170**.

**Figure 2** shows the drill string after it has moved the distance "d" shown by $t_1 - t_2$. Since the APD Device **170** is attached to the drill string **121**, the APD Device **170** also is shown moved by the distance d.

As noted earlier and shown in **Figure 2**, an APD Device **170a** may be attached to the wellbore in a manner that will allow the drill string **121** to move while the APD Device **170a** remains at a fixed location. **Figure 3** shows an embodiment wherein the APD Device is attached to the wellbore inside and is operated by a suitable device **172a**. Thus, the APD device can be attached to a location stationary relative to said drill string such as a casing, a liner, the wellbore annulus, a riser, or other suitable wellbore equipment. The APD Device **170a** is preferably installed so that it is in a cased upper section **129**. The device **170a** is controlled in the manner described with respect to the device **170 (Fig 1A)**.

Referring now to **Figures 4A-D**, there is schematically illustrated one arrangement wherein a positive displacement motor/drive **200** is coupled to a moineau-type pump **220** via a shaft assembly **240**. The motor **200** is connected to an upper string section **260** through which drilling fluid is pumped from a surface location. The pump **220** is connected to a lower drill string section **262** on which the bottomhole assembly (not shown) is attached at an end thereof. The motor **200** includes a rotor **202** and a stator **204**. Similarly, the pump **220** includes a rotor **222** and a stator **224**. The design of moineau-type pumps and motors are known to one skilled in the art and will not be discussed in further detail.

The shaft assembly **240** transmits the power generated by the motor **200** to the pump **220**. One preferred shaft assembly **240** includes a motor flex shaft **242** connected to the motor rotor **202**, a pump flex shaft **244** connected to the pump rotor **224**, and a coupling shaft **246** for joining the first and second shafts **242** and **244**. In one arrangement, a high-pressure seal

**248** is disposed about the coupling shaft **246**. As is known, the rotors for moineau-type motors/pump are subject to eccentric motion during rotation. Accordingly, the coupling shaft **246** is preferably articulated or formed sufficiently flexible to absorb this eccentric motion. Alternately or in combination, the shafts **242, 244** can be configured to flex to accommodate eccentric motion. Radial and axial forces can be borne by bearings **250** positioned along the shaft assembly **240**. In a preferred embodiment, the seal **248** is configured to bear either or both of radial and axial (thrust) forces. In certain arrangements, a speed or torque converter **252** can be used to convert speed/torque of the motor **200** to a second speed/torque for the pump **220**. By speed/torque converter it is meant known devices such as variable or fixed ratio mechanical gearboxes, hydrostatic torque converters, and a hydrodynamic converters. It should be understood that any number of arrangements and devices can be used to transfer power, speed, or torque from the motor **200** to the pump **220**. For example, the shaft assembly **240** can utilize a single shaft instead of multiple shafts.

As described earlier, a comminution device can be used to process entrained cutting in the return fluid before it enters the pump **200**. Such a comminution device (**Figure 1A)** can be coupled to the drive **200** or pump **220** and operated thereby. For instance, one such comminution device or cutting mill **270** can include a shaft **272** coupled to the pump rotor **224.** The shaft **272** can include a conical head or hammer element **274** mounted thereon. During rotation, the eccentric motion of the pump rotor **224** will cause a corresponding radial motion of the shaft head **274**. This radial motion can be used to resize the cuttings between the rotor and a comminution device housing **276**.

The **Figures 4A-D** arrangement also includes a supply flow path **290** to carry supply fluid from the device **200** to the lower drill string section **262** and a return flow path **292** to channel return fluid from the casing interior or annulus into and out of the pump **220**. The high pressure seal **248** is

interposed between the flow paths **290** and **292** to prevent fluid leaks, particularly from the high pressure fluid in the supply flow path **290** into the return flow path **292**. The seal **248** can be a high-pressure seal, a hydrodynamic seal or other suitable seal and formed of rubber, an elastomer, metal or composite.

Additionally, bypass devices are provided to allow fluid circulation during tripping of the downhole devices of the system **100 (Fig. 1A)**, to control the operating set points of the motor **200** and pump **220**, and to provide safety pressure relief along either or both of the supply flow path **290** and the return flow path **292**. Exemplary bypass devices include a circulation bypass **300**, motor bypass **310**, and a pump bypass **320**.

The circulation bypass **300** selectively diverts supply fluid into the annulus **194 (Fig. 1A)** or casing **C** interior. The circulation bypass **300** is interposed generally between the upper drill string section **260** and the motor **200**. One preferred circulation bypass **300** includes a biased valve member **302** that opens when the flow-rate drops below a predetermined valve. When the valve **302** is open, the supply fluid flows along a channel **304** and exits at ports **306**. More generally, the circulation bypass can be configured to actuate upon receiving an actuating signal and/or detecting a predetermined value or range of values relating to a parameter of interest (e.g., flow rate or pressure of supply fluid or operating parameter of the bottomhole assembly). The circulation bypass **300** can be used to facilitate drilling operations and to selective increase the pressure/flow rate of the return fluid.

The motor bypass **310** selectively channels conveys fluid around the motor **200**. The motor bypass **310** includes a valve **312** and a passage **314** formed through the motor rotor **202**. A joint **316** connecting the motor rotor **202** to the first shaft **242** includes suitable passages (not shown) that allow the supply fluid to exit the rotor passage **314** and enter the supply flow path **290**. Likewise, a pump bypass (not shown) selectively conveys fluid around

the pump **220**. The pump bypass includes a valve and a passage formed through the pump rotor **222** or housing. The pump bypass **320** can also be configured to function as a particle bypass line for the APD device. For example, the pump bypass can be adapted with known elements such as screens or filters to selectively convey cuttings or particles entrained in the return fluid that are greater than a predetermined size around the APD device. Alternatively, a separate particle bypass can be used in addition to the pump bypass for such a function. Alternately, a valve (not shown) in a pump housing **225** can divert fluid to a conduit parallel to the pump **220**. Such a valve can be configured to open when the flow rate drops below a predetermined value. Further, the bypass device can be a design internal leakage in the pump. That is, the operating point of the pump **220** can be controlled by providing a preset or variable amount of fluid leakage in the pump **220**. Additionally, pressure valves can be positioned in the pump **220** to discharge fluid in the event an overpressure condition or other predetermined condition is detected.

Additionally, an annular seal **299** in certain embodiments can be disposed around the APD device to direct the return fluid to flow into the pump **220** (or more generally, the APD device) and to allow a pressure differential across the pump **220**. The seal **299** can be a solid or pliant ring member, an expandable packer type element that expands/contracts upon receiving a command signal, or other member that substantially prevents the return fluid from flowing between the pump **220** (or more generally, the APD device) and the casing or wellbore wall. In certain applications, the clearance between the APD device and adjacent wall (either casing or wellbore) may be sufficiently small as to not require an annular seal.

During operation, the motor **200** and pump **220** are positioned in a well bore location such as in a casing **C**. Drilling fluid (the supply fluid) flowing through the upper drill string section **260** enters the motor **200** and causes the rotor **202** to rotate. This rotation is transferred to the pump rotor **222** by the shaft assembly **240**. As is known, the respective lobe profiles, size and

configuration of the motor **200** and the pump **220** can be varied to provide a selected speed or torque curve at given flow-rates. Upon exiting the motor **200**, the supply fluid flows through the supply flow path **290** to the lower drill string section **262**, and ultimately the bottomhole assembly (not shown). The return fluid flows up through the wellbore annulus (not shown) and casing **C** and enters the cutting mill **270** via a inlet **293** for the return flow path **292**. The flow goes through the cutting mill and enters the pump **220**. In this embodiment, the controller **180** (**Fig. 1A**) can be programmed to control the speed of the motor **200** and thus the operation of the pump **220** (the APD Device in this instance).

It should be understood that the above-described arrangement is merely one exemplary use of positive displacement motors and pumps. For example, while the positive displacement motor and pump are shown in structurally in series in **Figures 4A-B**, a suitable arrangement can also have a positive displacement motor and pump in parallel. For example, the motor can be concentrically disposed in a pump.

Referring now to **Figures 5A-B**, there is schematically illustrated one arrangement wherein a turbine drive **350** is coupled to a centrifugal-type pump **370** via a shaft assembly **390**. The turbine **350** includes stationary and rotating blades **354** and radial bearings **402**. The centrifugal-type pump **370** includes a housing **372** and multiple impeller stages **374**. The design of turbines and centrifugal pumps are known to one skilled in the art and will not be discussed in further detail.

The shaft assembly **390** transmits the power generated by the turbine **350** to the centrifugal pump **370**. One preferred shaft assembly **350** includes a turbine shaft **392** connected to the turbine blade assembly **354**, a pump shaft **394** connected to the pump impeller stages **374**, and a coupling **396** for joining the turbine and pump shafts **392** and **394**.

The **Figure 5A-B** arrangement also includes a supply flow path **410** for channeling supply fluid shown by arrows designated **416** and a return flow path **418** to channel return fluid shown by arrows designated **424**. The supply flow path **410** includes an inlet **412** directing supply fluid into the turbine **350** and an axial passage **413** that conveys the supply fluid exiting the turbine **350** to an outlet **414**. The return flow path **418** includes an inlet **420** that directs return fluid into the centrifugal pump **370** and an outlet **422** that channels the return fluid into the casing **C** interior or wellbore annulus. A high pressure seal **400** is interposed between the flow paths **410** and **418** to reduce fluid leaks, particularly from the high pressure fluid in the supply flow path **410** into the return flow path **418**. A small leakage rate is desired to cool and lubricate the axial and radial bearings. Additionally, a bypass **426** can be provided to divert supply fluid from the turbine **350**. Moreover, radial and axial forces can be borne by bearing assemblies **402** positioned along the shaft assembly **390**. Preferably a comminution device **373** is provided to reduce particle size entering the centrifugal pump **370**. In a preferred embodiment, one of the impeller stages is modified with shearing blades or elements that shear entrained particles to reduce their size. In certain arrangements, a speed or torque converter **406** can be used to convert a first speed/torque of the motor **350** to a second speed/torque for the centrifugal pump **370**. It should be understood that any number of arrangements and devices can be used to transfer power, speed, or torque from the turbine **350** to the pump **370.** For example, the shaft assembly **390** can utilize a single shaft instead of multiple shafts.

It should be appreciated that a positive displacement pump need not be matched with only a positive displacement motor, or a centrifugal pump with only a turbine. In certain applications, operational speed or space considerations may lend itself to an arrangement wherein a positive displacement drive can effectively energize a centrifugal pump or a turbine drive energize a positive displacement pump. It should also be appreciated that the present invention is not limited to the above-described arrangements.

For example, a positive displacement motor can drive an intermediate device such as an electric motor or hydraulic motor provided with an encapsulated clean hydraulic reservoir. In such an arrangement, the hydraulic motor (or produced electric power) drives the pump. These arrangements can eliminate the leak paths between the high-pressure supply fluid and the return fluid and therefore eliminates the need for high-pressure seals. Alternatively, a jet pump can be used. In an exemplary arrangement, the supply fluid is divided into two streams. The first stream is directed to the BHA. The second stream is accelerated by a nozzle and discharged with high velocity into the annulus, thereby effecting a reduction in annular pressure. Pumps incorporating one or more pistons, such as hammer pumps, may also be suitable for certain applications.

Referring now to **Figure 6A**, there is schematically illustrated one arrangement wherein an electrically driven pump assembly **500** includes a motor **510** that is at least partially positioned external to a drill string **502**. In a conventional manner, the motor **510** is coupled to a pump **520** via a shaft assembly **530**. A supply flow path **504** conveys supply fluid designated with arrow **505** and a return flow path **506** conveys return fluid designated with arrow **507**. As can be seen, the **Figure 6A** arrangement does not include leak paths through which the high-pressure supply fluid **505** can invade the return flow path **506**. Thus, there is no need for high pressures seals.

In one embodiment, the motor **510** includes a rotor **512**, a stator **514**, and a rotating seal **516** that protects the coils **512** and stator **514** from drilling fluid and cuttings. In one embodiment, the stator **514** is fixed on the outside of the drill string **502**. The coils of the rotor **512** and stator **514** are encapsulated in a material or housing that prevents damage from contact with wellbore fluids. Preferably, the motor **510** interiors are filled with a clean hydraulic fluid. In another embodiment not shown, the rotor is positioned within the flow of the return fluid, thereby eliminating the rotating seal. In such an arrangement, the stator can be protected with a tube filled with clean hydraulic fluid for pressure compensation.

Referring now to **Figure 6B**, there is schematically illustrated one arrangement wherein an electrically driven pump **550** includes a motor **570** that is at least partially formed integral with a drill string **552**. In a conventional manner, the motor **570** is coupled to a pump **590** via a shaft assembly **580**. A supply flow path **554** conveys supply fluid designated with arrow **556** and a return flow path **558** conveys return fluid designated with arrow **560**. As can be seen, the **Figure 6B** arrangement does not include leak paths through which the high-pressure supply fluid **556** can invade the return flow path **558**. Thus, there is no need for high pressures seals.

It should be appreciated that an electrical drive provides a relatively simple method for controlling the APD Device. For instance, varying the speed of the electrical motor will directly control the speed of the rotor in the APD device, and thus the pressure differential across the APD Device. Further, in either of the **Figure 6A or 6B** arrangements, the pump **520** and **590** can be any suitable pump, and is preferably a multi-stage centrifugal-type pump. Moreover, positive displacement type pumps such a screw or gear type or moineau-type pumps may also be adequate for many applications. For example, the pump configuration may be single stage or multi-stage and utilize radial flow, axial flow, or mixed flow. Additionally, as described earlier, a comminution device positioned downhole of the pumps **520** and **590** can be used to reduce the size of particles entrained in the return fluid.

It will be appreciated that many variations to the above-described embodiments are possible. For example, a clutch element can be added to the shaft assembly connecting the drive to the pump to selectively couple and uncouple the drive and pump. Further, in certain applications, it may be advantages to utilize a non-mechanical connection between the drive and the pump. For instance, a magnetic clutch can be used to engage the drive and the pump. In such an arrangement, the supply fluid and drive and the return fluid and pump can remain separated. The speed/torque can be transferred by a magnetic connection that couples the drive and pump elements, which

are separated by a tubular element (e.g., drill string). Additionally, while certain elements have been discussed with respect to one or more particular embodiments, it should be understood that the present invention is not limited to any such particular combinations. For example, elements such as shaft assemblies, bypasses, comminution devices and annular seals discussed in the context of positive displacement drives can be readily used with electric drive arrangements. Other embodiments within the scope of the present invention that are not shown include a centrifugal pump that is attached to the drill string. The pump can include a multi-stage impeller and can be driven by a hydraulic power unit, such as a motor. This motor may be operated by the drilling fluid or by any other suitable manner. Still another embodiment not shown includes an APD Device that is fixed to the drill string, which is operated by the drill string rotation. In this embodiment, a number of impellers are attached to the drill string. The rotation of the drill string rotates the impeller that creates a differential pressure across the device.

While the foregoing disclosure is directed to the preferred embodiments of the invention, various modifications will be apparent to those skilled in the art. It is intended that all variations within the scope and spirit of the appended claims be embraced by the foregoing disclosure.

WHAT IS CLAIMED IS:

1. A drilling system for drilling a wellbore, comprising

(a) a drill string having a drill bit at an end thereof;

(b) a source of drilling fluid supplying drilling fluid under pressure into the drill string (a "supply fluid"), the drilling fluid returning uphole via an annulus around the drill string (a "return fluid");

(c) an active pressure differential device ("APD Device") associated with the return fluid to create a pressure drop across said APD Device to reduce pressure in the wellbore downhole of said APD Device;

(d) a drive assembly coupled to said APD Device for energizing said APD Device; and

(e) a sealing member positioned between said APD Device and said drive assembly, said sealing member at least partially providing a barrier between the supply fluid and the return fluid.

2. The drilling system of claim 1 wherein said APD Device is selected from one of (a) a positive displacement pump, (b) a centrifugal type pump, and (c) a Moineau-type pump.

3. The drilling system of claim 1 wherein said drive assembly is selected from one of (a) a positive displacement drive, (b) a turbine drive, (c) a electric motor, (d) a hydraulic motor, (e) a Moineau-type motor, and (f) rotation of said drill string.

4. The drilling system of claims 1-3 further comprising a bypass for selectively diverting fluid around one of said APD device and said drive assembly.

5. The drilling system of claim 1-4 further comprising a speed converter interposed between drive assembly and said APD device, said speed converter being adapted to convert a first speed associated with said drive assembly to a selected second speed associated with said APD device.

6. The drilling system of claim 5 wherein said speed converter is selected from a group consisting of (i) a gear drive, (ii) a hydrostatic drive, and (iii) a hydrodynamic drive.

7. The drilling system of claim 1-6 further comprising a comminution device positioned downhole of said APD device, said comminution device configured to reduce the size of cuttings entrained in the return fluid.

8. The drilling system of claim 7 wherein said comminution device includes a shaft coupled to a rotor associated with said APD Device and a conical head mounted on an end thereof, said shaft having a radial motion corresponding to an eccentric motion of said rotor, said conical head thereby engaging and reducing the size of the cuttings.

9. The drilling system of claims 1 and 3-6 wherein said APD Device comprises a centrifugal type pump and said comminution device comprises a shearing member configured as a stage in said centrifugal type pump.

10. The drilling system of claim 1 further comprising an annular seal disposed around said APD device, said annular seal causing the return fluid to flow into said APD device and allowing said APD device to create a differential pressure thereacross.

11. The drilling system of claims 1, 3-6 and 10 further comprising a controller that controls the operation of said APD Device.

12. The drilling system of claim 11 wherein said controller is located at one of: (i) at the surface; (ii) in a drilling assembly attached to the drill string; and (iii) adjacent said APD Device.

13. The drilling system of claim 11 wherein said controller controls said APD Device in response to one of: (i) a parameter of interest; (ii) programmed instructions provided to said controller; (iii) instructions from a remote location; and (iv) a downhole measured parameter.

14. The drilling system of claim 11 wherein said controller includes one of (a) microprocessor and a memory, and (b) a hydro-mechanical device.

15. The drilling system of claim 11 wherein said controller is positioned in the wellbore; and further comprises a telemetry system for transmitting signals to said controller.

16. The drilling system of claim 11 wherein said controller controls the operation of said APD Device to control the pressure in the wellbore to one of: (i) maintain the wellbore bottomhole pressure at a predetermined value; (ii) maintain the wellbore bottomhole pressure within a selected range; (iii) maintain at-balance condition; and (iv) maintain under-balance condition.

17. The drilling system of claims 1, 3-6 and 10 further comprising a sensor for detecting a parameter of interest.

18. The drilling system of claim 17 wherein said sensor detects a parameter selected from a group consisting of (i) drilling parameters, (ii) drilling assembly parameters, and (iii) formation evaluation parameters.

19. The drilling system of claim 17 wherein said sensor is positioned at a predetermined location selected from a group consisting of (i) a surface location,

(ii) at said APD Device, (iii) at wellhead equipment, (iv) in the supply fluid, (v) along said drill string, (vi) at a drilling assembly connected to said drill string, (vii) in the return fluid upstream of said APD device, and (viii) in the return fluid downstream of said APD device.

20. The drilling system of claims 1, 3-6, 10 and 17 further comprising a blocking device downhole of said APD Device that blocks the return fluid flow when the drilling fluid supply is interrupted or stopped.

21. The drilling system of claims 1, 3-6, 10 and 17 wherein said APD device is attached to one of (a) said drill string, (b) a location stationary relative to said drill string, (c) the annulus, and (d) a riser.

22. A drilling system for drilling a wellbore, comprising

(a) a drill string having a drill bit at an end thereof;

(b) a source of drilling fluid supplying drilling fluid under pressure into the drill string (a "supply fluid"), said drilling fluid returning uphole via an annulus around the drill string (a "return fluid");

(c) an active pressure differential device ("APD Device") placed in the annulus to create a pressure drop across said APD Device to reduce pressure in the wellbore downhole of said APD Device, said APD Device in fluid communication with the return fluid; and

(d) an electric drive assembly being substantially isolated from the supply fluid.

23. The drilling system of claim 22 wherein said electric drive assembly is disposed in a location selected from (a) in housing that substantially isolates said electric drive assembly from the supply fluid, and (b) on the outside of said drill string.

24. The drilling system of claim 22 further comprising a speed converter interposed between said drive assembly and said APD device, said speed converter adapted to convert a first speed associated with said drive assembly to a selected second speed associated with said APD device.

25. The drilling system of claim 24 wherein said speed converter is selected from a group consisting of (i) a gear drive, (ii) a hydrodynamic drive, and (iii) a hydrodynamic drive.

26. The drilling system of claims 22-23 further comprising a comminution device positioned downhole of said APD device, said comminution device configured to reduce the size of particles entrained in said drilling fluid.

27. The drilling system of claim 26 wherein said comminution device is coupled to said drive assembly and energized thereby.

28. The drilling system of claim 26 wherein said comminution device comprises a shearing member configured as a stage in a centrifugal type pump associated with said APD Device.

29. The drilling system of claims 22-23 and 26 further comprising an annular seal disposed around said APD device, said annular seal causing drilling fluid to flow into said APD device.

30. The drilling system of claim 22 wherein said APD Device includes one of: (i) a turbine; and (ii) a centrifugal pump.

31. A method for drilling a wellbore, comprising

(a) providing a drill string having a drill bit at an end thereof;

(b) supplying drilling fluid under pressure into the drill string (a "supply fluid"), the drilling fluid returning uphole via an annulus around the drill string (a "return fluid");

(c) positioning an active pressure differential device ("APD Device") in fluid communication with the return fluid to create a pressure drop across the APD Device to reduce pressure in the wellbore downhole of the APD Device;

(d) coupling a drive assembly to the APD Device for energizing said APD Device; and

(e) providing an at least partial barrier between the supply fluid and the return fluid by positioning a sealing member positioned between the APD Device and the drive assembly.

32. The method of claim 31 wherein said APD Device is selected from one of (a) a positive displacement pump, (b) a centrifugal type pump, and (c) a Moineau-type pump.

33. The method of claim 31 wherein said drive assembly is operated by one of (a) a positive displacement drive, (b) a turbine drive, (c) a electric motor, (d) a hydraulic motor, (e) a Moineau-type pump, and (f) rotation of the drill string.

34. The method of claims 31-33 further comprising positioning a comminution device downhole of the APD device, the comminution device configured to reduce the size of cuttings entrained in the return fluid.

35. The method of claim 34 wherein the comminution device includes a shaft coupled to a rotor associated with the APD Device and a conical head mounted on an end thereof, the shaft having a radial motion corresponding to an eccentric motion of the rotor, the conical head thereby engaging and reducing the size of the cuttings.

36. The method of claim 34 wherein the APD Device comprises a centrifugal type pump and the comminution device comprises a shearing member configured as a stage in the centrifugal type pump.

37. The method of claims 31-34 further comprising disposing an annular seal around the APD device, the annular seal causing the return fluid to flow into the APD device and allowing the APD device to create a differential pressure.

38. The method of claim 31-34 further comprising controlling the operation of the APD Device with a controller.

39. The method of claim 38 further comprising positioning the controller at one of: (i) at the surface; (ii) in a drilling assembly attached to the drill string; and (iii) adjacent the APD Device.

40. The method of claim 38 wherein the controller controls the APD Device in response to of: (i) a parameter of interest; (ii) programmed instructions provided to the APD Device; (iii) instructions provided to the APD Device from a remote location; and (iv) a downhole detected parameter.

41. The method of claim 38 further comprising positioning the controller in the wellbore; and transmitting signals to the controller via a telemetry system.

42. The method of claim 38 wherein the controller controls the operation of the APD Device to control the pressure in the wellbore to one of: (i) maintain the wellbore bottomhole pressure at a predetermined value; (ii) maintain the wellbore bottomhole pressure within a selected range; (iii) maintain at-balance condition; and (iv) maintain under-balance condition.

43. The method of claims 31-34 and 37 further comprising detecting a parameter of interest with a sensor.

44. The method of claim 43 wherein the sensor detects a parameter selected from a group consisting of (i) drilling parameters, (ii) drilling assembly parameters, and (iii) formation evaluation parameters.

45. The method of claim 43 further comprising positioning the sensor at a predetermined location selected from a group consisting of (i) a surface location, (ii) at the APD Device, (iii) at wellhead equipment, (iv) in the supply fluid, (v) along the drill string, (vi) at a drilling assembly connected to the drill string, (vii) in the return fluid upstream of the APD device, and (viii) in the return fluid downstream of the APD device.

46. The method of claims 31-34, 37 and 43 further comprising attaching the APD device to one of (a) the drill string, (b) a location stationary relative to the drill string, (c) the annulus, and (d) a riser.

47. A method for drilling a wellbore, comprising

(a) providing a drill string having a drill bit at an end thereof;

(b) supplying drilling fluid under pressure into the drill string (a "supply fluid"), the drilling fluid returning uphole via an annulus around the drill string (a "return fluid");

(c) placing an active pressure differential device ("APD Device") in the annulus to create a pressure drop across the APD Device to reduce pressure in the wellbore downhole of the APD Device, the APD Device in fluid communication with the return fluid; and

(d) driving the APD device with an electric drive assembly that is substantially isolated from the supply fluid.

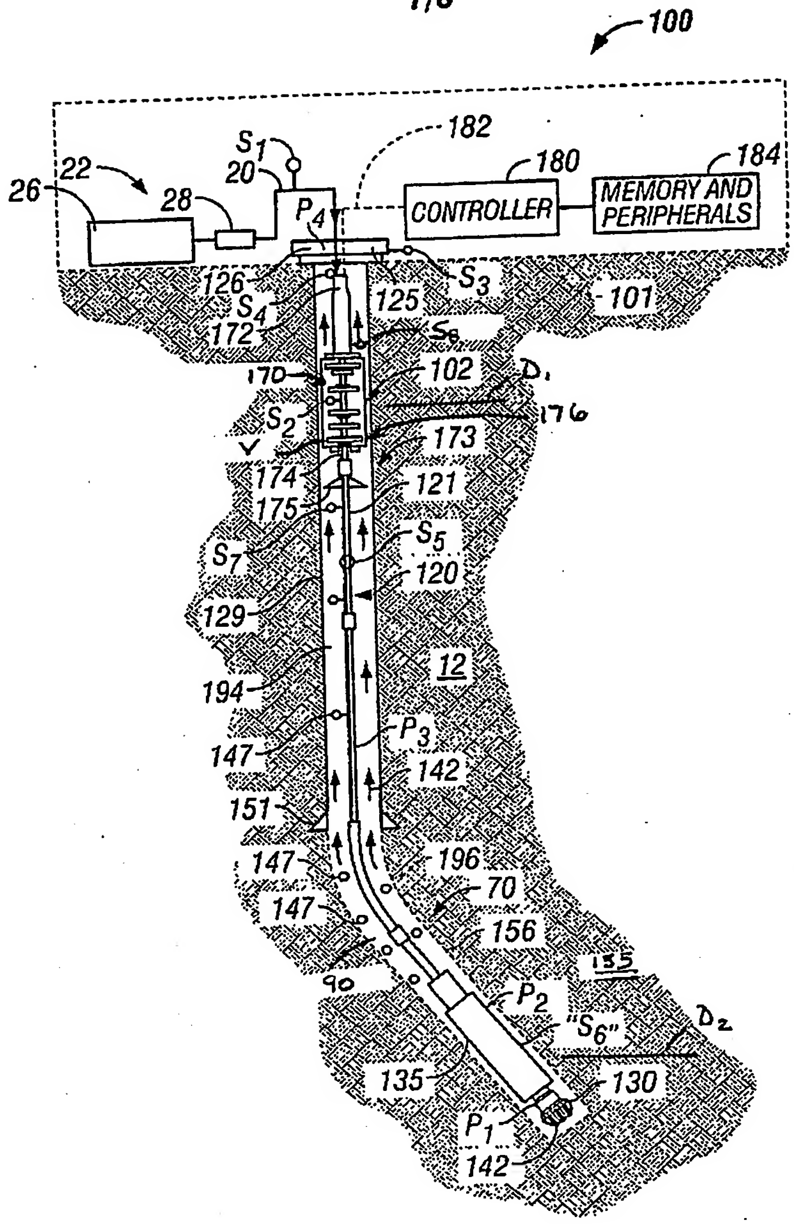
48. The method of claim 47 further comprising disposing the electric drive assembly in a location selected from (a) in housing that substantially isolates the electric drive assembly from the supply fluid, and (b) on the outside of the drill string.

49. The method of claim 47 further comprising positioning a comminution device downhole of the APD device, the comminution device configured to reduce the size of particles entrained in the return fluid.

50. The method of claim 47 further comprising disposing an annular seal around the APD device, the annular seal causing drilling fluid to flow into the APD device and providing a pressure differential across the APD device.

51. The method of claim 47 wherein said APD Device includes one of: (i) a turbine; and (ii) a centrifugal pump.

1/8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180
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22
28
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172
170
102
$D_1$
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$S_2$
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194
$P_3$
147
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FIG. 1A

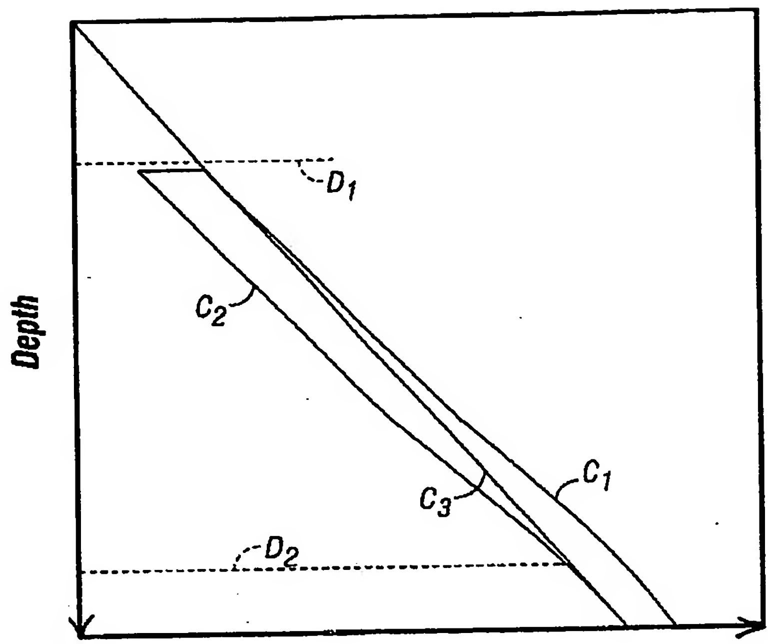



FIG. 1B

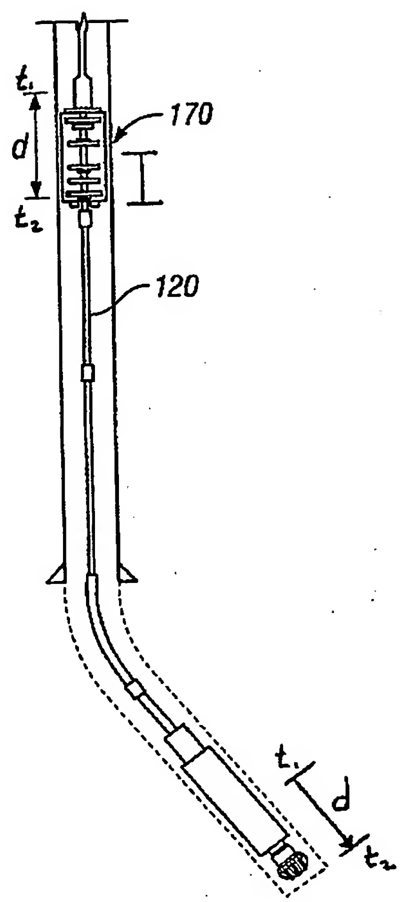
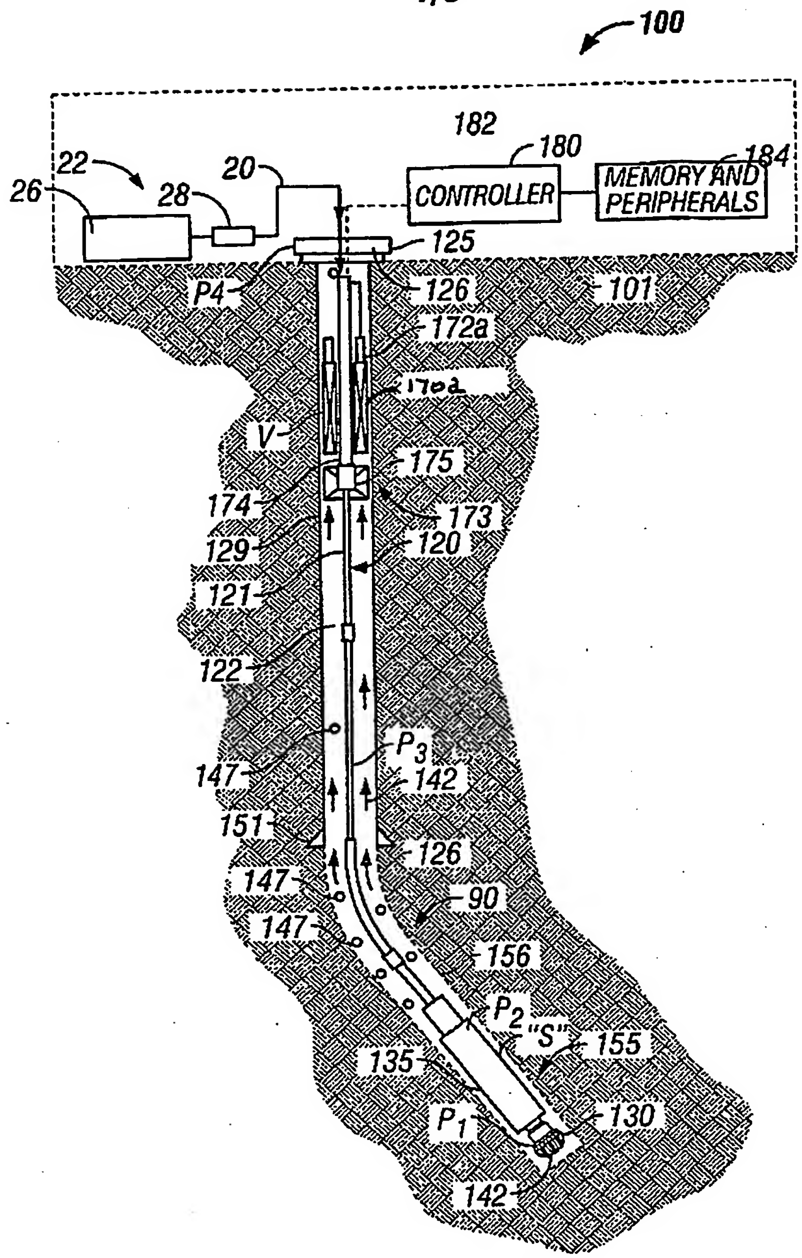



FIG. 2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182
180
184
CONTROLLER
MEMORY AND PERIPHERALS
22
20
28
26
125
P4
126
101
172a
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V
175
174
173
129
120
121
122
147
P3
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151
126
147
90
147
156
P2
"S"
155
135
P1
130
142

FIG. 3

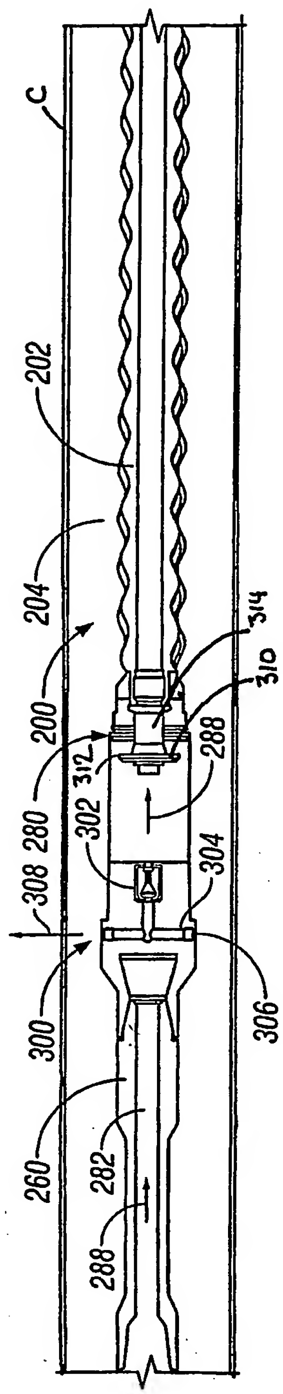
C
202
204
200
280
308
300
260
282
288
314
310
312
288
302
304
306

FIG. 4A

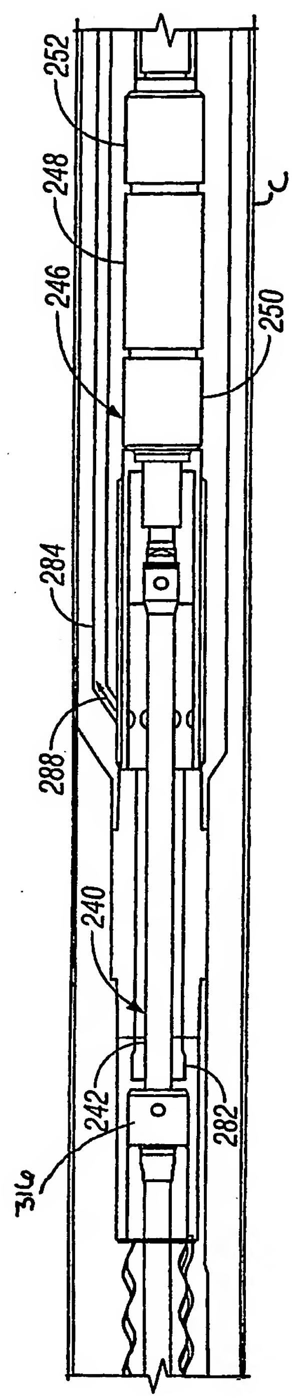
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FIG. 4B

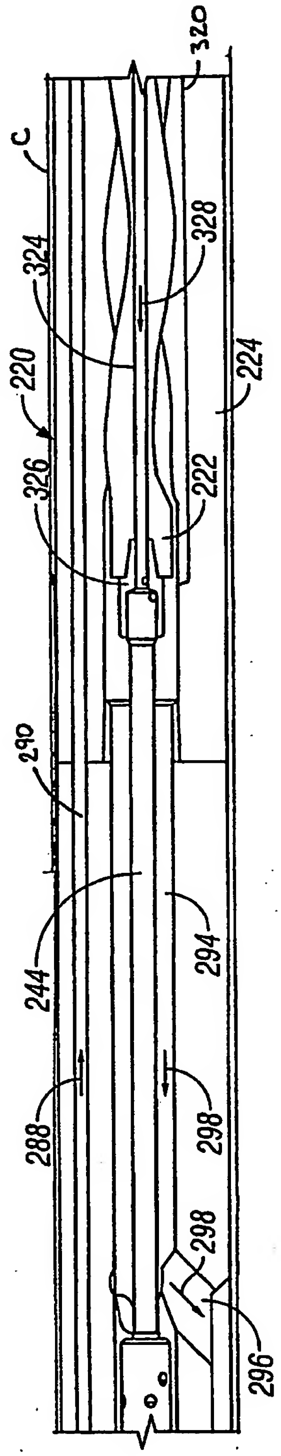

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FIG. 4C

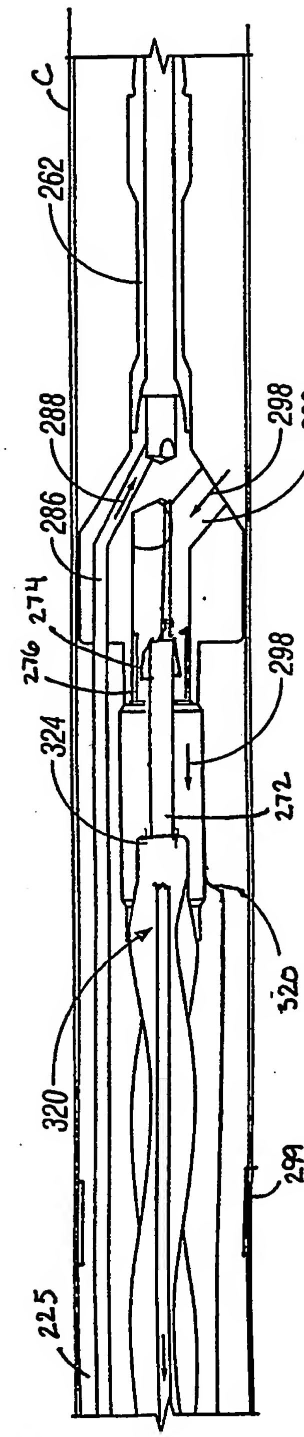

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FIG. 4D

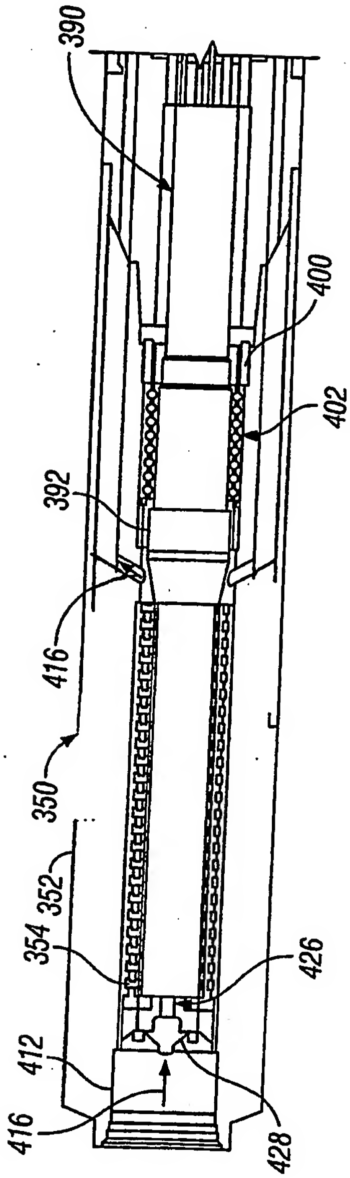
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FIG. 5A

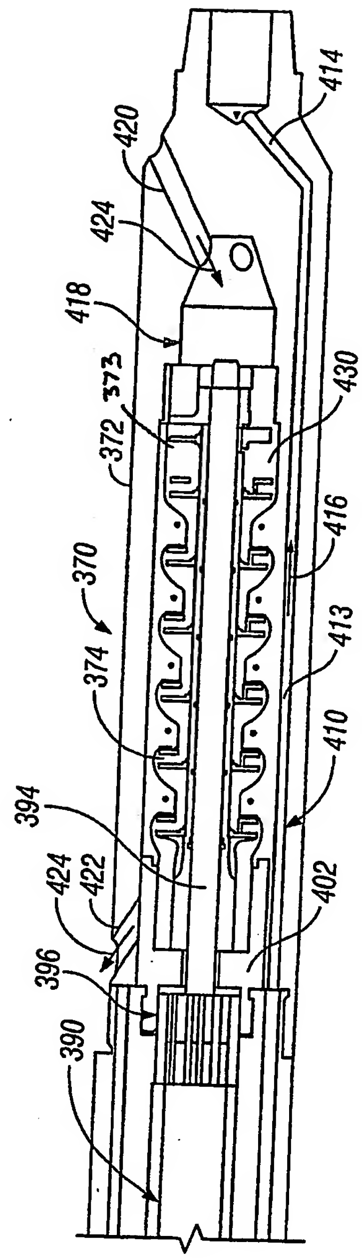
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FIG. 5B

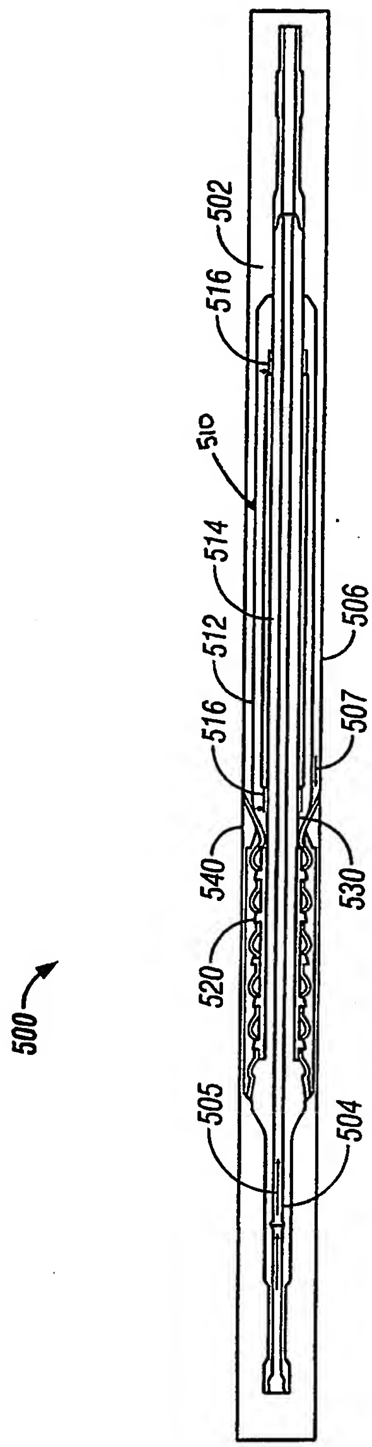

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FIG. 6A

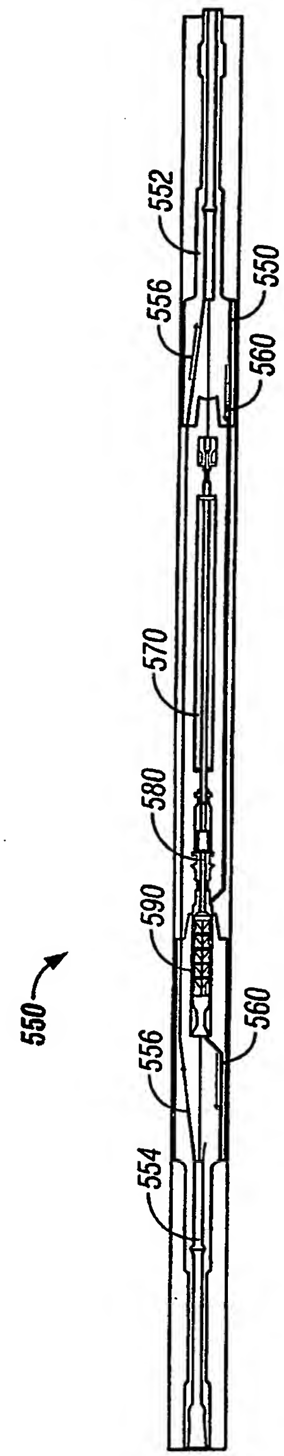

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FIG. 6B

# INTERNATIONAL SEARCH REPORT

International Application No
PCT/US 02/29738

**A. CLASSIFICATION OF SUBJECT MATTER**
IPC 7 E21B21/08 E21B21/00

According to International Patent Classification (IPC) or to both national classification and IPC

**B. FIELDS SEARCHED**

Minimum documentation searched (classification system followed by classification symbols)
IPC 7 E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

EPO-Internal

**C. DOCUMENTS CONSIDERED TO BE RELEVANT**

| Category ° | Citation of document, with indication, where appropriate, of the relevant passages | Relevant to claim No. |
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| Y | figure 2<br>--- | 24,25 |

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[X] Further documents are listed in the continuation of box C.

[X] Patent family members are listed in annex.

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Date of the actual completion of the international search: 13 December 2002

Date of mailing of the international search report: 30/12/2002

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## INTERNATIONAL SEARCH REPORT

International Application No
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